equatorial energy inc. 2000 annual report

equatorial energy inc. is a Calgary-based independent corporation engaged in the acquisition, exploration, and development of petroleum and natural gas interests in Western Canada and Indonesia. The Corporation achieved record operational and financial results in 2000 and enters 2001 with more prospects and more resources than ever in the Corporation's history.

2000 Daily Production

■ Canada 4,535 boepd
■ Indonesia 4,525 bopd

Reserves
(Proved + 1/2 Probable)

■ Indonesia 24,121 mstb
■ Canada 12,814 mboe

financial highlights

(000s, except per share amounts)	2000	1999
Revenue, net of royalties and government share	$ **87,735**	$ 46,742
Cash flow from operations	**50,478**	17,269
Net income	**14,093**	2,456
Working capital*	**7,973**	3,576
Debt	**65,274**	73,671
Shareholders' equity	**42,517**	30,309
Cash flow per share		
– basic	**2.62**	1.20
– fully diluted	**1.79**	0.83
Earnings per share		
– basic	**0.70**	0.13
– fully diluted	**0.51**	0.12

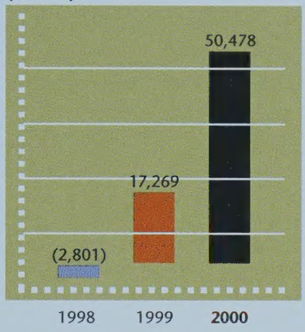
*excluding current portion of long-term debt

operating highlights

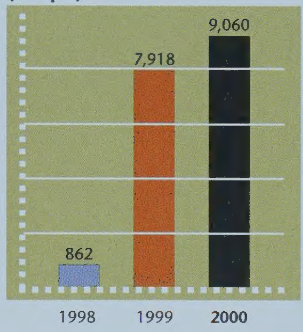
	Production	Reserves (Proven + 1/2 Probable)
Western Canada		
Crude oil and NGL's	2,457 bopd	6,593 mstb
Natural gas	20,779 mcfpd	62.2 bcf
Indonesia		
Crude oil	4,525 boepd	24,121 mstb
Total boes (at 10:1)	9,060 boepd	36,935 mboe
Total boes (at 6:1)	10,445 boepd	41,082 mboe

	Gross	Net
Drilling		
Oil	30	28.3
Gas	9	7.9
Dry	10	8.8
Total	49	45.0
Success Rate	80%	80%
Undeveloped Land (acres)		
Western Canada	370,000	247,000

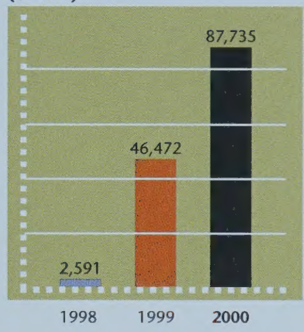
Cash Flow from Operations ($000s)



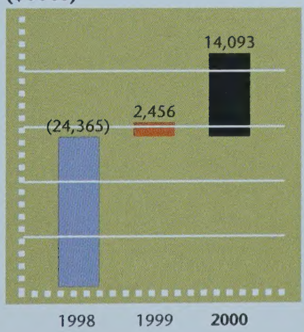
Production (boepd)



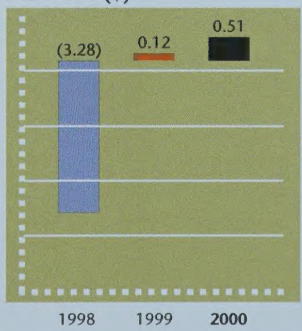
Net Revenue ($000s)



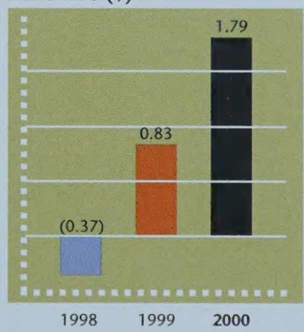
Earnings ($000s)

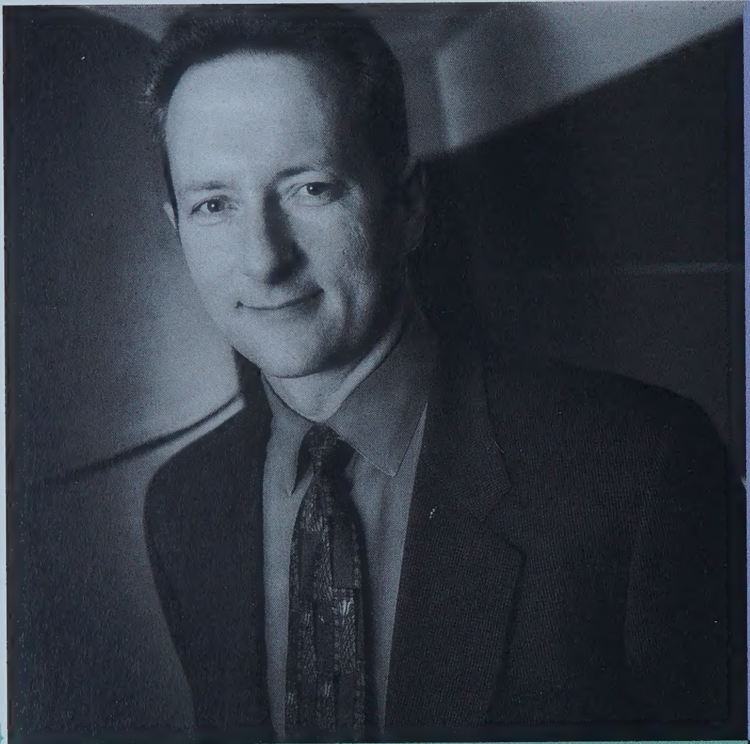


Fully Diluted Earnings Per Share ($)



Fully Diluted Cash Flow Per Share ($)





David N. Matheson
President and Chief Executive Officer

Marshall Abbott
Chairman of the Board

On behalf of the Company's Board of Directors, we are pleased to report the results of our Company's operations for the year ended December 31, 2000. During the year we experienced the culmination of 5 years of hard work by a dedicated group of employees in two geographically, politically, and culturally diverse countries. Our consolidated Canadian and Indonesian operations set Company records in all major categories of performance measurement, including:

- A 88% increase in net revenues to $87,735,000;
- A 192% increase in cash flow from operations to $50,478,000;
- A 474% increase in net earnings to $14,093,000;
- A production increase of 14% to an average of 9,060 boepd;
- Drilling "success" rates of 71% in Canada and 86% in Indonesia on a volume of 21 and 28 wells respectively; and
- Three year established F&D costs of $4.32/boe.

Subsequent to the year-end, we repaid the residual US$11,600,000 balance owing on a loan secured to finance our acquisition of the Sembakung oilfield on the north-east coast of Kalimantan, Indonesia in 1998. Our Indonesian operations are now free of non-trade indebtedness.

These results confirm the "contrarion" acquisition strategy our Company employed in 1998 and 1999 during a time of depressed prices for hydrocarbons worldwide. We set industry-wide records for "lowest price paid per barrel of proven reserves" when we acquired our Canadian assets in 1999 and our Sembakung property a year earlier. We now have production increases, combined with an inventory of development and exploration prospects, in both Canada and Indonesia, at a time of higher prices for both oil and gas. Our undeveloped land base of 247,000 net acres in Canada and our three contract areas in Indonesia will be the Company's foundation for continued growth in both countries.

Canada

For the first time in recent memory, the spot price for natural gas on NYMEX, the prime US market indices for natural gas, closely approximates the price paid to Canadian producers in Western Canada. Canadian natural gas producers are collectively unable to supply the main Nova Corporation transmission line requirement of 13 bcfpd, falling about 1.5-2 bcfpd short. This situation has resulted in unprecedented prices for Canadian natural gas in the Cdn.$7.00 – Cdn.$9.00/mcf range, prices equal to those paid to our counterpart natural gas producers in the United States. We do not expect this market to soften dramatically in the near term.

During 2000, we modified our drilling plans in Canada to take advantage of this situation and drilled new natural gas discoveries at Malmo and Berry. Each of these relatively shallow discoveries are capable of delivering 2 mmcfpd and will yield several development drilling locations for our 47-well,

2001 Canadian drilling program. Our capital budget for Canada is $18,000,000, almost all of which will be applied to develop and explore for natural gas.

During 2000, we also restructured our operations in Canada into distinct "core areas", assigning senior operations managers to each of these areas, and providing for these managers to report to the newly created position of "Chief Operating Officer-Canada". This reporting structure is already providing our Company with increased flexibility to change, a reduction in Canadian unit operating costs through sale of non-core properties, and the creation of additional senior executive time to pursue strategic acquisitions and financing alternatives.

Indonesia

The success of our shallow development drilling program at Arahan-Banjarsari ("AB") in South Sumatra during 2000, with production increases to a level of 2,000 bopd from an initial starting rate in January, 2000 of 605 bopd, has created other opportunities for our Company. We have discussed the possibility of the Company assuming the role of "Contractor" for similar exploitation opportunities on some Government oilfields in South Sumatra with PERTAMINA, the state oil company of Indonesia. Further, our Company recently acquired an 80% interest in a 3rd Indonesian "Technical Assistance Contract" ("TAC") to develop the Kruh Field, South Sumatra. Kruh is the largest TAC in Indonesia in terms of acreage, covering an area of 258.1 square kilometers. The Company's reputation as an efficient, low-cost Contractor has assisted in attracting these opportunities.

The AB Project and Kruh operations are managed entirely by Indonesian employees of the Company. We are most proud of this fact. Our South Sumatra operations, managed by Director K.A. Sjaiful Achmad and General Manager Suryana, reflect the success the Company has experienced in overcoming social, cultural, and economic boundaries for the mutual benefit of our Company's shareholders, PERTAMINA, and the people of the Republic of Indonesia.

At Sembakung, our Indonesian management team worked side-by-side with our Canadian professionals to build a road into the swamps of the northeast coast of Kalimantan and commence drilling operations on time and on budget. We employed Canadian technology and utilized Foremost track vehicles, normally applied to transport equipment in the muskeg regions of Northern Alberta, to build the required road and drilling pads, and transport our drilling rig from pad to pad. This technology saved approximately US$5,000,000 in "up-front" road construction costs and allowed the drilling phase of the Project to commence on time. Production accordingly increased from 3,000 bopd to 4,000 bopd during the year.

From a political-risk perspective, our positive experiences in Indonesia are similar to those of most Western and other Asian companies operating in the country. The senior politicians in Jakarta have managed to at least stabilize the separatist movements in certain outlying Provinces as well as maintain the integrity of the democratic government. Economic and central banking reforms are underway, albeit at a pace that is frustrating to most international investors. The International Monetary Fund has a

substantive investment in Indonesia and has publicly vowed to pledge further financial support to Indonesia if needed.

Our industry, however, has also prevailed in Indonesia since the turn of the century. The international oil and gas community has a large investment in Indonesia, due, primarily, to the reserve potential of the massive underdeveloped geological basins, but also because of Pertamina's enviable reputation for maintaining the integrity of its production-sharing contracts with international Contractors. We are able to produce and sell our share of crude oil production at world prices, receive payment in US dollars, and generate an internationally competitive return on investment. For these reasons, combined with the number of prime exploitation opportunities currently available to our Company, we will continue to focus and grow in Indonesia.

2001 Outlook

Our Company faces a number of challenges in the forthcoming year:

1. In Canada, the industry is experiencing 30% annual well decline rates on new natural gas wells, considerably above the average of 15-20% that has prevailed for many years. Our country's inventory of lower risk natural gas prospects is declining rapidly and related finding costs are increasing.
2. Canadian financial institutions now have more investment alternatives to consider. The timely communication of financial data and the enviable performance of high technology, telecommunications and Internet equities in the earlier part of 2000, has diminished traditional sources of growth capital for companies of our size in our industry.
3. Capital for Indonesian growth opportunities is available but expensive.
4. The "multiples of operating cash flow" which investors pay for Canadian junior and intermediate oil and gas equities is about 50% of historical levels, thus diminishing shareholder market capitalization.

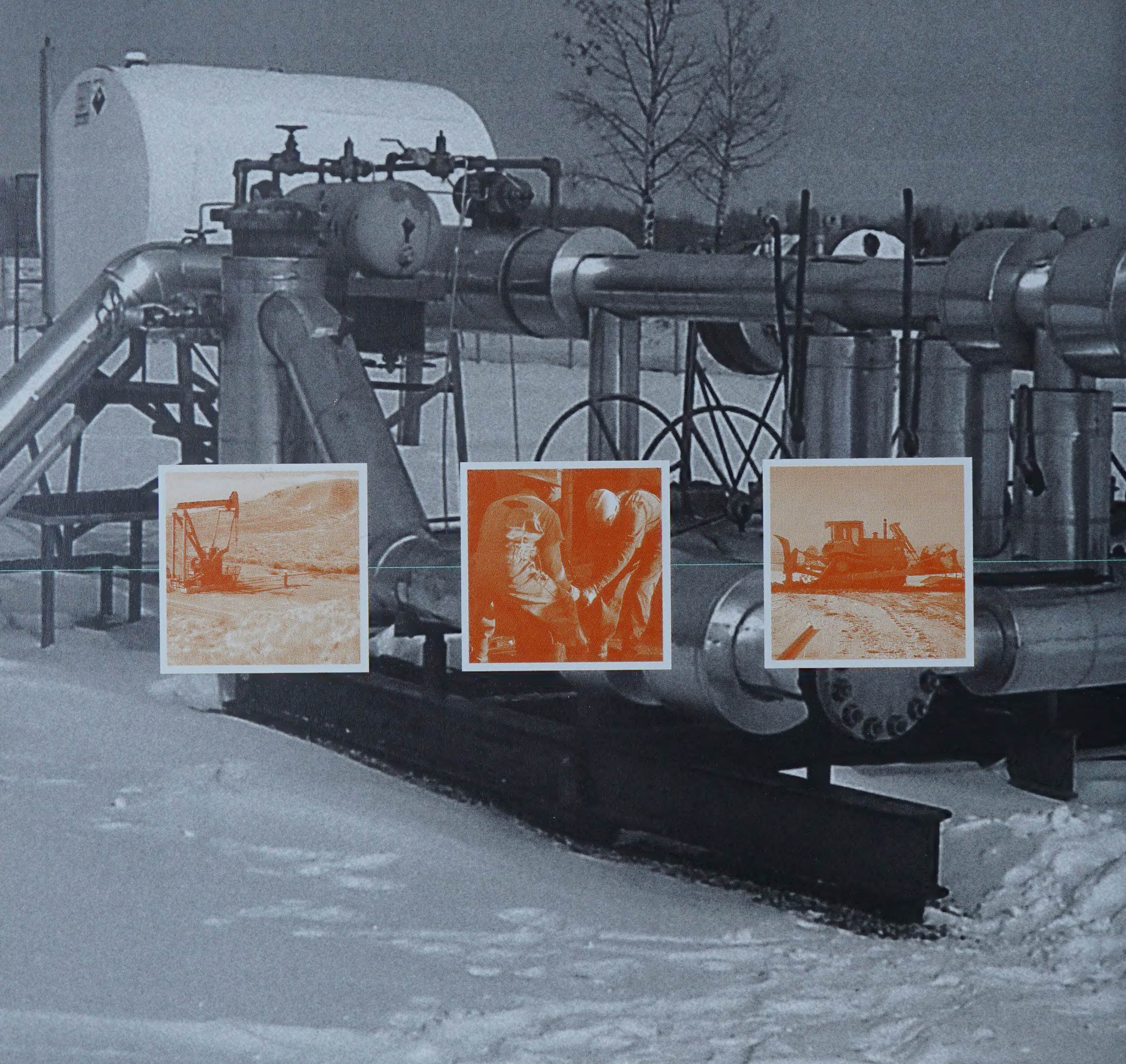
We are confident we can overcome these challenges and continue to achieve controlled growth. We will be able to fund our 2001 capital program of $51,000,000 through prudent management of operating cash flow. We will continue to rely on the dedication of our employees in both Canada and Indonesia to maximize the return on each dollar of invested shareholder capital. Production growth will not occur at any expense and we will continue to emphasize the "bottom line" profitability of the Company while maintaining our debt to equity ratio in line with the investing community's expectations.

We would like to thank our shareholders, the Board of Directors, our employees and their families for their collective support of our Company during 2000.

Yours truly,

G. Marshall Abbott
Chairman of the Board

David N. Matheson
President and Chief Executive Officer



Canada
2000


Indonesia
2000


Canada is the third largest producer of natural gas in the world. Canadian exports of natural gas increased 130% to 9 bcfpd during the past decade.
Yukon Territory
Northwest Territories
Nunavut
British Columbia
Alberta
Saskatchewan
Manitoba
Ontario
UNITED STATES
GORDONDALE
KAYBOB
BIGORAY
MALMO
WILLESDEN GREEN
BERRY
GRAND FORKS
SOUTHEAST SASKATCHEWAN

Canada

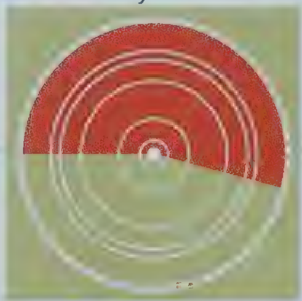
Equatorial's Canadian reserve base is 51% oil and 49% gas and has a strong prospect inventory with 247,000 net acres of undeveloped land. Operated properties account for 78% of production and 87% of reserves. Working interests average 79% for reserves and 63% for lands.

During 2000, 21 wells were drilled, which resulted in 7 oil wells, 8 gas wells and 6 dry holes for a total of 15 net producing wells. Average Canadian production volume for the year was 4,535 boepd, of which 46% was natural gas and 54% oil and NGL's.

Canadian Production

Operated 78%
Non-operated 22%

Canadian Daily Production



Oil 2,457 bopd
Gas (at 10:1) 2,078 boepd

Canadian Land (Net)

Undeveloped 247,000 acres
Developed 125,000 acres

Core Properties

During 2001, Equatorial will focus on high growth and high production properties. It's core operated properties of Berry, Bigoray, Gordondale, Malmo, Grand Forks and Willesden Green and the non-operated Kaybob Unit No. 2 generate 64% of Canadian production and represent 71% of Canadian boe reserve volumes.

Berry

Equatorial holds an average working interest of 78% in the Berry property located approximately 150 kilometres northeast of Calgary, Alberta. Production is primarily from the Mannville zone. Equatorial's 2000 geological program resulted in a new Mannville Channel play, with the first well drilled and placed on production in February 2001 at 1 mmcfpd and 50 bopd. Equatorial anticipates drilling two follow-up locations in late March 2001.

Bigoray

The Bigoray property is located approximately 300 kilometres northwest of Calgary. Working interests vary from 25% to 100%, with the majority of the lands 100%-owned.

There are 8 producing wells on the Bigoray property, with seven wells currently producing sweet gas and natural gas liquids from the Glauconite and Ostracod formations. Gas produced from the Bigoray property is rich in natural gas liquids and is processed at a third party facility which provides deep-cut processing, capable of ethane plus recovery. Equatorial has successfully re-stimulated one well in late 2000, taking the production rate from 900 mcfpd to 2,000 mcfpd. This well is the first of several re-stimulation candidates.

The majority of the reserves in the Bigoray property are associated with the Glauconite formation. Geological and pressure information has demonstrated that the Glauconite wells can be grouped into various common drainage pools, which are competitively drained.

Gordondale

Equatorial holds various interests, ranging from 6.25% to 100% in the Gordondale property. This property is located in northwestern Alberta, approximately 300 kilometres northwest of Edmonton. The property consists of both oil and gas reserves, with oil production coming from wells in the Halfway "K" oil pool. The possibility of a waterflood and production of the gas cap from the Halfway "K" is currently being evaluated. A 52% working interest Charlie Lake gas well was brought on in 2000 and is currently producing approximately 1.5 mmcfpd. Exploratory drilling and follow-up development drilling in the Gordondale Balsam area resulted in a Kiskatinaw oil pool discovery. Two producing wells are capable of in excess of 250 boepd each. Both wells are currently rate restricted by Alberta Energy Utilities Board-enforced production allowables pending the outcome of further reservoir drilling and delineation work.

Malmo

Equatorial holds working interests between 83% and 100% in the Malmo property, located approximately 65 kilometres northeast of Red Deer, Alberta. Production is 100% sweet dry gas, primarily from the Belly River zone. The 2000 drilling program resulted in a new Belly River channel play, with the first well on production in mid-2000 and currently producing at a rate of 600 mcfpd and the second well placed on production in January 2001 at a rate of 2 mmcfpd. An extensive development program is planned for 2001.

Canadian Reserves by Category

- Proved Producing 8,282 mboe
- Proved Non-producing 1,900 mboe
- 1/2 Probable 2,632 mboe

Canadian Reserves by Product (proved + 1/2 probable)

- Oil 6,593 mstb
- Gas (at 10:1) 6,221 mboe

Grand Forks

Equatorial holds a 96% working interest in the Grassy, Grand Forks, Hays, Enchant and Winnifred producing areas, collectively referred to as "Grand Forks". The majority of the lands within the Grand Forks area are located approximately 200 kilometers southeast of Calgary, with primarily natural gas production from the Sawtooth, Glauconite, Bow Island and second white specs formations.

Three new wells were drilled on the Grand Forks and Grassy properties in 2000, and multi-well programs are planned for the Grand Forks and Winnifred areas

in 2001. In addition, Equatorial is pursuing further exploration potential within the current land holdings and surrounding lands.

Willesden Green

Willesden Green is a gassy oil property. When acquired by Equatorial, this property consisted of ten suspended Glauconitic oil wells and approximately 10 boepd from one producing Glauconite well. In 1999, Equatorial successfully drilled a 100% working interest Cardium oil well. This well commenced production in December 1999 at approximately 100 bopd and 400 mcfpd of gas. Equatorial recompleted three additional 100% working interest wells in the Cardium Zone in 2000 and one more to this point in 2001. A compressor installation is currently underway to resolve a gas processing restriction and to bring on additional production. Once completed, this will accommodate three additional planned Cardium recompletions and bring on approximately 1 mmcfpd of gas production.

Kaybob South Triassic Unit No.2

Equatorial owns a 29.94% non-operated working interest in the Kaybob South Triassic Unit No. 2, approximately 250 kilometres northwest of Edmonton. Production consists of light, slightly sour, 42 degree API gravity oil, associated gas and natural gas liquids. The unit commenced production in 1967, is currently under waterflood.

The reservoir is the subject of the unit is a stratigraphic trap within the Montney Formation. Hydrocarbon entrapment results from a facies change from a dolomite coquina into a tight siltstone in a northward direction. Production is from 18 oil wells (5 net producing wells) with pressure support provided by 13 water injectors in a peripheral waterflood scheme. The injectors are located both along the western boundary of the unit and along the oil-gas interface.

Since December of 1998, three successful horizontal re-entry wells have been drilled. Additional drilling potential has been identified. Re-entry drilling has proved effective in reducing production declines and tapping into un-depleted portions of the reservoir.

Non-Core Properties

The non-core properties provide significant cash flow at relatively low operating costs. However, no development or exploration activities are anticipated for these areas in 2001, and Equatorial will actively pursue swapping these properties for properties within its core areas. These properties represent 29% of Canadian production and 24% of Canadian reserve volumes. The most significant of these properties is located in southeast Saskatchewan.

Saskatchewan

The Saskatchewan area consists of properties in Wauchope and Arcola. Wauchope is approximately 130 kilometres southeast of Regina. The Corporation holds a 97% working interest in Wauchope, which produced 254 bopd during 2000. The pool has been developed with both horizontal and vertical wells.

The Arcola property is approximately 200 kilometres southeast of Regina. Equatorial holds a 50% working interest in the property, which produced 125 bopd during 2000.

Other Properties

Certain properties have been consolidated into a package that Equatorial intends to sell in 2001. The sale of these assets will allow the Corporation to better focus on its core areas and is expected to reduce the Corporation's operating expenses. These properties represent 7% of Canadian production and 5% of Canadian reserve volumes.

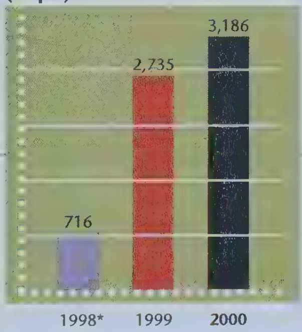
Indonesia, an OPEC member, produces approximately 1.5 million bopd and exports 400,000 bopd

Indonesia

The Indonesian reserve base is 100% oil and 100% operated by Equatorial. Operations in Indonesia are conducted through production sharing arrangements called "Technical Assistance Contracts" (TACs) with Pertamina, the state oil company. The oil and mineral rights are retained 100% by Pertamina for Indonesia, and Equatorial owns a contractual interest in the oil produced in each contract area.

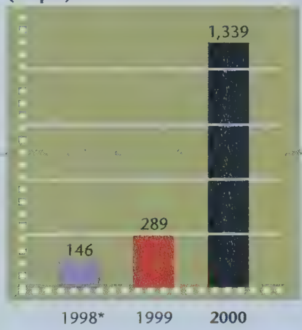
In 2000, Equatorial drilled and completed 28 wells, resulting in 23 oil wells, 1 suspended gas well and 4 dry holes. At Sembakung, the Company drilled and completed 6 new oil wells resulting in 5 producing wells and 1 suspended well pending a remedial workover. At Tanjung Lontar, the Company drilled and completed 22 shallow oil wells, of which 18 are producing, and 1 gas well. Average Indonesian production volume for the year was 4,525 bopd, which is approximately 50% of the total Company production.

Sembakung Production (bopd)



*Purchased September 1998

Tanjung Lontar Production (bopd)



*Commenced deliveries May 1998

Sembakung

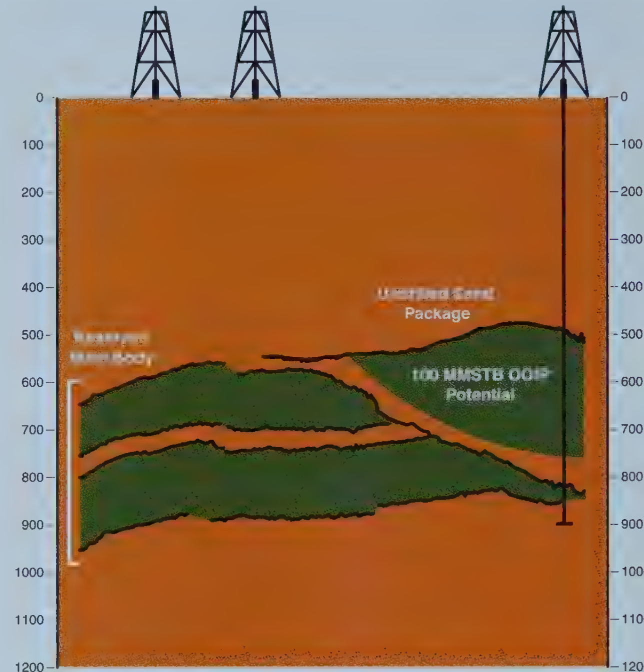
Equatorial has an 80% interest in the Sembakung oil field in northeast Kalimantan, Indonesia. Under the terms of the joint venture agreement with the 20% Indonesian partner, the Company is entitled to 100% of net operating profits until all capital advances and accrued interest are recovered. At December 31, 2000, the total balance of amount due to Equatorial to be recovered prior to the partner's participating in net operating profits is US$12,900,000.

The reservoir quality at Sembakung is excellent, with porosity ranging from approximately 15% to 30% and permeability in the 200 to 2,000 mD range. The crude oil is 37 degree API gravity with very low wax content and no sulfur. It is comprised of a series of stacked deltaic reservoirs of the Miocene Tabul Formation, in which some 33 separate reservoir zones are identified. It is very shallow, with the upper reservoirs at 450 metres and the base of the currently productive zones at approximately 1000 metres. The field has a number of discreet gas caps recognized from logging.

Two deeper wells were drilled a number of years ago which encountered gas and significant reservoir sands. Existing two-dimensional seismic showed evidence of untested reservoir potential. Accordingly, three-dimensional seismic data was acquired and processed in 2000. Initial interpretation suggests significant extensional drilling potential to the south of the main Sembakung field area.

Since purchasing the property in 1998, Equatorial has completed a "floating road", built drilling pads and implemented a directional drilling program. Two Foremost 8-tracked vehicles are used to construct roads and move heavy drilling equipment from pad to pad within the field.

The first of the development wells, SBK-15, spudded on December 5, 1999 and reached total depth on January 5, 2000. The well was cased and initially put on production, under natural flow, from two virgin sands with an initial stable production rate of approximately 680 bopd. Following the decline of these zones, other identified pay zones were perforated, an electric submersible pump installed and the well put back on production. Production from this well at December 31, 2000 was 264 bopd, with approximately 1,300 bopd of water.



Drilling operations continued with the drilling of SBK-16. This well has been temporarily suspended due to a casing part in the seven-inch casing string. Equatorial anticipates that this well will be worked over during 2001 to repair the well and place it on production. The SBK-17, SBK-18, SBK-19 and SBK-20 wells were also drilled in 2000. All but SBK-19 were on production during 2000. SBK-19 suffered reservoir damage due to high mud weight during drilling. This well is expected to be worked-over with fracture stimulation in early 2001. As of December 31, 2000, three of the wells drilled in 2000 were on production at an incremental new oil rate of 1,238 bopd. At that time, the SBK-20 well was shut-in due to failure of an electric submersible pump in the well.

The initial development plan is to drill up to an additional 23 wells, convert and implement a pressure maintenance scheme.

Significant numbers of uncompleted zones have been identified in wells drilled prior to Equatorial operating the property. As a result, new zones can be perforated or existing zones reperforated to enhance production. In addition, zones on a few of these wells were abandoned and plugged after originally being tested with high oil cuts. If economic, these plugs will be removed and the isolated zones will be put into production.

Tanjung Lontar

The Tanjung Lontar TAC is located in the southern end of the island of Sumatra. The TAC is comprised of four old oil fields. The two northerly fields, Tanjung Lontar and Sengkuang, have productive horizons at 800 – 1000 metres in depth. The Arahan and Banjarsari fields have reservoirs generally shallower than 300 metres.

All the fields produce very light sweet crude (47° API) from a series of stacked deltaic sands of the Muara Enim Formation. The reservoirs have excellent porosity and permeability characteristics, with porosities of 20 – 28% and permeabilites ranging from approximately 200 mD to over 1,000 mD.

Equatorial has executed a very successful shallow drilling program at Arahan-Banjarsari. In 2000, this program concentrated on the western area of the Banjarsari pool where 18 wells were drilled targeting the main reservoir interval discovered in the eastern area of the Banjarsari field. In addition, three wells were drilled to target very shallow, historically productive zones, generally from 40 metres depth to around 150 metres depth. As drilling moved westward, results showed a dramatic increase from net pay of 6 – 8 metres to amounts in excess of 36 metres, at depths shallower than 250 metres.

Banjarsari drilling in 2000 brought total Tanjung Lontar production to 2,100 bopd in 2000, which subsequently declined to 1,600 bopd by the end of the year. Accordingly, reserves of 328,000 barrels proved and 360,000 probable were added in 2000.

During 2000, the WAR-1 exploration well was drilled on the west side of the Lematang river to evaluate an undrilled anticline recognized on two-dimensional seismic data. Testing of this well to the west of Arahan recovered only fresh water. New seismic data will be acquired in the second quarter of 2001 to determine if the well was drilled in the optimum structural and stratigraphic location. The development of the Arahan field on the west side of the Lematang river will be pursued in 2001.

The significant success of operations in the western part of the Banjarsari field has encouraged the Corporation to plan to continue an extensive development and delineation program over the field, both to the east and

south. It is planned that up to 15 wells will be drilled in the Banjarsari, Arahan and westward extension of the Arahan-Banjarsari anticline during 2001. Two new wells will be drilled in the eastern part of the Tanjung Lontar anticline, one well on the south side of the Sengkuang anticline and an exploration well on the north side of the Sengkunag anticline beginning in the third quarter of 2001. In addition, a small two-dimensional exploration seismic program will be undertaken to enhance understanding of the structural and stratigraphic aspects of the field and to help in locating additional well locations in the Tanjung Lontar and Sengkuang fields.

Kruh

During 2000, Equatorial acquired an 80% interest in the Kruh TAC which includes the Kruh and North Kruh fields. The contract area is very large, covering an area of 258.1 square kilometers, on which the two oil fields have been discovered. The Company will conduct a geologic and geoseismic study of the Kruh fields in 2001 with the objective of generating a definitive plan of development and exploration for late 2001 or early 2002.

Reserves

Equatorial's reserves are reported as of December 31, 2000 by Gilbert Laustsen Jung Associates Ltd. The Company's proved reserves are 51% oil and natural gas liquids and 49% gas in Canada and 100% oil in Indonesia. On a combined basis, the Company's proved reserves are 83% oil and natural gas liquids and 17% gas.

Summary of Reserve Values and Volumes

	Reserves		Before Tax Net Present Values (Cdn $000s)			
	Oil & NGL's mstb	Gas mmcf	0%	10%	15%	20%
Canada						
Total proved	5,174	50,083	$ 199,000	$ 147,000	$ 132,000	$ 120,000
1/2 probable	1,419	12,126	41,500	23,500	18,500	15,500
Total proved plus 1/2 probable	6,593	62,209	$ 240,500	$ 170,500	$ 150,500	$ 135,500
Indonesia						
Total proved	13,020	–	$ 50,000	$ 38,000	$ 34,000	$ 31,000
1/2 probable	11,101	–	63,500	35,000	26,500	21,000
Total proved plus 1/2 probable	24,121	–	$ 113,500	$ 73,000	$ 60,500	$ 52,000
Total Company						
Total proved	18,194	50,083	$ 249,000	$ 185,000	$ 166,000	$ 151,000
1/2 probable	12,520	12,126	105,000	58,500	45,000	36,500
Total proved plus 1/2 probable	30,714	62,209	$ 354,000	$ 243,500	$ 211,000	$ 187,500

Net Asset Value

Net Asset Value (10% PV) – December 31, 2000	Canada	Indonesia	Total
Total proved plus 1/2 probable values, before tax ($000s)	170,500	73,000	243,500
Undeveloped land ($75/acre)	17,500	–	17,500
	188,000	73,000	261,000
Dilution increment [1]			9,310
Debt, net of working capital			(57,301)
Hedge – mark to market [2]			(37,200)
Other			(3,000)
Net asset value – December 31, 2000			172,809
Net asset value per share (fully diluted)		$	6.04
Pro-forma net asset value per share [3]		$	5.69

[1] assumes conversion of options and warrants into cash.

[2] based on pricing assumptions used by Equatorial's independent reserve engineers.

[3] after giving effect to Special Warrants issued subsequent to year end.

Finding and Development Costs

Finding Costs	2000	3 Year Average
Net capital expenditures ($000s)		
Acquisitions	1,982	106,638
Exploration	5,446	9,721
Development	33,807	51,852
Other	261	1,227
Dispositions	(5,522)	(7,522)
	35,974	161,916
Net proved + 1/2 probable reserve additions (mboe, gas converted at 10:1)		
Acquisitions	140	37,952
Discoveries	1,273	3,502
Revisions	1,473	(3,974)
Dispositions	(10)	(10)
	2,876	37,470
Finding and development costs	12.53	4.32

Production and Reserves by Location

	2000 Average Production Rates			Oil & NGL's Reserve Volumes (mstb)				Natural Gas Reserve Volumes (mmcf)			
	Oil & NGL's bopd	Natural Gas mcfpd	boe (10:1)	Proved	1/2 Probable	Total	%	Proved	1/2 Probable	Total	%
Core Properties											
Berry	58	749	133	105	16	121		1,284	962	2,246	
Bigoray	271	4,383	709	875	328	1,203		13,170	4,739	17,909	
Gordondale	170	2,268	397	618	446	1,064		6,578	2,292	8,870	
Malmo	—	1,846	185	–	–	–		3,625	627	4,252	
Grand Forks	532	708	602	794	306	1,100		2,317	285	2,602	
Willesden Green	136	918	228	260	–	260		2,625	90	2,715	
Kaybob	636	186	654	1,193	205	1,398		480	83	563	
	1,803	11,058	2,908	3,845	1,301	5,146	16.75	30,079	9,078	39,157	62.94
Non-Core Properties	393	9,126	1,306	771	81	852	2.77	18,752	2,843	21,595	34.71
Other Properties	261	595	321	558	37	595	1.94	1,252	205	1,457	2.35
Total Canada	2,457	20,779	4,535	5,174	1,419	6,593	21.46	50,083	12,126	62,209	100.00
Sembakung	3,186	–	3,186	12,430	10,921	23,351	76.03	–	–	–	
Tanjung Lontar	1,339	–	1,339	590	180	770	2.51	–	–	–	
Total Indonesia	4,525	–	4,525	13,020	11,101	24,121	78.54	–	–	–	
Total Equatorial	**6,982**	**20,779**	**9,060**	**18,194**	**12,520**	**30,714**	**100.00**	**50,083**	**12,126**	**62,209**	**100.00**

Land Holdings – December 31, 2000

	Gross Developed Acres	Net Developed Acres	Average Working Interest %	Gross Undeveloped Acres	Net Undeveloped Acres	Average Working Interest %
Core Properties						
Berry	14,908	6,738	45	8,382	4,776	57
Bigoray	9,330	6,968	75	4,586	2,696	59
Gordondale	27,517	13,561	49	36,215	17,670	49
Malmo	13,030	11,898	91	17,438	15,508	89
Grand Forks	27,599	20,262	73	36,610	24,475	67
Willesden Green	2,372	1,329	56	2,372	2,031	86
Kaybob	5,377	1,344	25	9,647	4,117	43
	100,132	62,101	62	115,250	71,274	62
Non-Core Properties	92,700	51,713	56	213,462	151,334	71
Other Properties	27,272	11,206	41	41,011	24,329	59
Canadian Totals	220,104	125,020	57	369,723	246,937	67

Management's Discussion and Analysis

The following discussion of the Corporation's financial affairs should be read in conjunction with the Consolidated Financial Statements and related notes contained elsewhere in this Annual Report.

Results of Operations

In 2000, the Corporation completed its first full year of operating the Canadian and Indonesian properties acquired in 1999 and 1998 and achieved the objective of being self-funding in both jurisdictions.

In Canada, the Corporation invested $12,810,000 on capital projects while Canadian cash flow from operations before hedging was $38,160,000. Similarly, in Indonesia, the Corporation invested $24,417,000 on capital projects while Indonesian cash flow from operations before hedging was $29,694,000.

In 2000, only 5% of total capital additions of $41,496,000 were acquisitions. In each of 1999 and 1998 acquisitions were the dominant component of the capital investment program. In 1999, $70,168,000, or 78% of total capital investment of $89,999,000 related to the acquisition of assets in Western Canada. In 1998, $29,229,000 or 77% of the total capital investment program of $38,102,000 related to the acquisition of the Sembakung field in Indonesia. The strategy of acquiring assets during the low point in the commodity price cycle and exploiting during the higher commodity price time period has proven to be successful, as demonstrated in the 2000 financial results.

Year Ended December 31, 2000 Compared with the Year Ended December 31, 1999

Production

Production in 2000 was 21 mmcfpd and 6,982 bopd, or 9,060 boepd and increased 14% from volumes of 7,918 boepd in 1999. The increase resulted from exploration and development activities, a large proportion of which was from development drilling of the Corporation's Tanjung Lontar and Sembakung properties in Indonesia. In Indonesia, production increased by 50% from an average of 3,024 in 1999 to an average of 4,525 in 2000 as a result of this drilling program. Canadian average production in 2000 was 4,535 boepd as compared to 4,893 boepd in 1999. The decrease is attributable to production declines as offset by the Canadian capital program.

In 1999, Equatorial diversified its operating base by adding Canadian oil and gas activities to the existing Indonesian oil and gas operations. Prior to 1999 the Corporation had production only in Indonesia.

Revenues

Revenues of $128,582,000 in 2000 increased by 77% over 1999 revenues of $72,257,000. This increase reflects volume increases and the effect of higher commodity prices, particularly Canadian natural gas prices.

Realized commodity prices for the 2000 year were $40.75 per barrel for oil and Ngls and $5.55 per mcf for natural gas. This compares to realized prices in 1999 of $25.78 for oil and Ngls and $2.81 per mcf for natural gas. Oil and NGL prices increased in the first quarter of 2000 and were relatively constant for the balance of the year. Natural gas prices increased significantly during the last half of 2000 and reached a high of $10.14 per mcf average in the fourth quarter.

As a result of commodity hedging transactions, oil and natural gas revenues for 2000 were reduced by $17,376,000 (1999 – $2,458,000). These hedges were entered into in association with the Corporation's Canadian property acquisition in 1999. Details of the Corporation's commodity hedge positions are in Note 12 to the Consolidated Financial Statements.

The corporation expects that commodity prices with remain strong though 2001.

Royalties/Government Share

Royalties are a combination of freehold, crown and overriding royalties in Canada and government share in Indonesia. The apparently high royalty rates are a reflection of the nature of the Corporation's contractual relationship with the Indonesian authorities, as displayed in the segmented information in Note 9 of the Consolidated Financial Statements.

Royalties on production from Indonesian properties represent the entitlement of the Indonesian government to a portion of the Corporation's production, and are recorded using rates in effect under the terms of contracts at the time of production.

Included in the calculation of government share in the Sembakung TAC is a concept of "Non-Shareable Oil" (NSO). NSO is a calculated amount of total production that is not subject to sharing, although the Corporation is responsible for operations relating to this production. The Indonesian government pays for that portion of operating costs relating to NSO, but is not responsible for any capital costs. NSO volumes in 2000 were 1,196 bopd, as compared to 1,375 bopd in 1999. These volumes decline, under the terms of the TAC, at 13.3% annually.

In addition to NSO at Sembakung, government share includes a portion of the production from each TAC based upon the terms of the contract. Under the terms of the Corporation's TACs, the Corporation is entitled to use gross proceeds of production of shareable oil to recover substantially all of the non-capital costs incurred in the development of the contract area as well as current year depreciation for capital costs and any costs unrecovered in prior years. The maximum cost recovery in any year is 80% of shareable oil revenue. Upon recovery of all costs, the Corporation's share of revenue reverts to approximately 29%.

This cost recovery concept is similar to a typical 100% for 50% farm-in in Western Canada, with the two major differences being that in Indonesia the costs are on an area basis rather than well by well, and in Indonesia the government pays their share of operating costs both before and after payout.

	2000			1999		
Royalty/Government Share	**Canada**	**Indonesia**	**Total**	Canada	Indonesia	Total
Revenue ($000s)	**$ 75,753**	**$ 70,205**	**$ 145,958**	$ 45,420	$ 29,295	$ 74,715
Royalty/government share ($000s)	**15,376**	**25,471**	**40,847**	8,796	16,719	25,515
Government share (%)	**20%**	**36%**	**28%**	19%	57%	34%

Royalty rates declined in 2000 as capital expenditures at Sembakung resulted in cost recovery of higher production volumes, and the NSO component declined in total and as a proportion of total production. The Corporation anticipates royalty rates in Canada to increase marginally due to the price sensitive nature of the fiscal regime, while government share in Indonesia is expected to increase as the Corporation's cost pools are recovered.

Operating Costs

Operating costs increased from $20,169,000 in 1999 to $25,310,000 in 2000, which reflect volume increases and higher per barrel amounts in 2000.

In Canada, operating costs rose to $7.94 per boe in 2000 as compared to $6.22 per boe in 1999 due to increased third party processing costs for gas being processed through non operated plants. Rationalization through property sales and consolidation of interests in 2001 are expected to lower operating costs per boe in Canada.

In Indonesia, under the terms of The Corporation's TACs, the Corporation has the right to recover all costs defined as operating costs in each TAC against available revenues generated by the TAC. Operating costs consist of current year non-capital costs, current year depreciation on capital costs and current year allowed recovery of prior year's unrecovered operating costs. This recovery of operating costs relates to 100% of the Shareable Oil and is reflected in the Corporation's share of revenues. Operating costs relating to Non Shareable Oil are paid by the government and are not included in the Corporation's income statement.

Much of the Indonesian field operating costs are fixed in nature. Consequently, as production increased during 2000, operating costs per boe declined. The Corporation expects this to happen again in 2001 as Indonesian production volumes continue to increase.

	2000			1999		
Operating Costs	**Canada**	**Indonesia**	**Total**	Canada	Indonesia	Total
Operating costs ($000s)	$ 13,142	$ 12,168	$ 25,310	$ 11,111	$ 9,058	$ 20,169
Total boe	1,655,401	1,651,545	3,306,946	1,786,070	1,103,880	2,889,950
Cost/boe	$ 7.94	$ 7.37	$ 7.65	$ 6.22	$ 8.21	$ 6.98

General and Administrative Expenses

General and administrative expenses increased from $3,253,000 in 1999 to $5,716,000 in 2000, reflecting a full year's cost associated with managing the Western Canadian assets acquired in 1999. On a boe basis, general and administrative costs were $1.73 in 2000 compared to $1.13 in 1999.

General and	2000			1999		
Administrative Expenses	**Canada**	**Indonesia**	**Total**	Canada	Indonesia	Total
Gross	$ 7,147	$ 2,218	$ 9,365	$ 4,470	$ 1,202	$ 5,672
Allocated to						
– Capital projects	1,794	347	2,141	1,025	1,018	2,043
– Operating projects	132	–	132	146	–	146
– Third party recoveries	608	768	1,376	230	–	230
Net expenses	4,613	1,103	5,716	3,069	184	3,253
Average cost per boe						
– Gross	$ 4.32	$ 1.34	$ 2.83	$ 2.50	$ 1.09	$ 1.96
– Net	$ 2.79	$ 0.67	$ 1.73	$ 1.72	$ 0.17	$ 1.13

Taxes

The Corporation paid no cash income taxes in 2000. At December 31, 2000, estimated tax pools in Canada total $85,300,000, of which non-capital losses approximate $28,300,000.

Growth in the Corporation has resulted in higher federal capital taxes. The Saskatchewan capital tax is in substance a royalty, and is reported as part of royalty expense. Indonesia collects no capital taxes.

Cash Taxes		**2000**		1999
Federal capital tax	$	**429,000**	$	180,000
Average cost per boe (at 10:1)	$	**0.26**	$	0.10

Effective January 1, 2000, the Corporation adopted the new accounting recommendation of the Canadian Institute of Chartered Accountants, "Income Taxes". The standard has been adopted retroactively without restatement of the 1999 consolidated financial statements, with previously unrecognized future income tax liabilities relating to prior years being charged against the Corporation's opening retained earnings for 2000.

The Corporation expects to pay no cash income taxes in 2001 depending on commodity prices. Given continued high commodity prices, the Corporation will be cash taxable in 2002.

Depletion, Depreciation and Site Restoration

In 2000, depletion, depreciation and site restoration increased to $21,368,000 from $14,365,000 in 1999. On a boe basis, depletion, depreciation and site restoration was $6.54 in 2000 and $4.97 in 1999. In 1999, the low rates are due to the low cost of the acquisitions in 1999 and 1998. Subsequent development expenditures relating to proved reserves resulted in a higher per barrel depletion expense in 2000, particularly in Indonesia.

Depletion, Depreciation and Site Restoration ($000s)		**2000 Canada**		**2000 Indonesia**		**2000 Total**		1999 Canada		1999 Indonesia		1999 Total
Depletion and depreciation	$	8,884	$	11,574	$	20,458	$	8,506	$	3,851	$	12,357
Site restoration		1,180		—		1,180		2,008		–		2,008
Total	$	10,064	$	11,574	$	21,638	$	10,514	$	3,851	$	14,365
Average per boe	$	6.08	$	7.01	$	6.54	$	5.89	$	3.49	$	4.97
Site restoration per boe	$	0.71	$	–	$	0.36	$	1.12	$	–	$	0.69

Increasing cost of services and capital being invested on projects bringing on proved non-producing reserves on stream will result in higher depletion rates in 2001.

Net Earnings

Net earnings in 2000 were $14,093,000 as compared to 1999 when the Corporation recorded its first ever earnings of $2,456,000. This increase is due to high commodity prices, offset by hedging losses and increased depletion rates per barrel. The low depletion rates in 1999 are the direct result of low cost acquisitions in both 1998 and 1999.

Liquidity and Capital Resources

The Corporation entered 2000 with $70,095,000 of debt net of working capital. At the end of 2000 the amount of net debt was reduced to $57,301,000, and by the end of the first quarter of 2001 net debt is anticipated to be approximately $49,000,000. The Corporation has used the recent period of high commodity prices to reduce debt with cash flow in excess of that required for capital projects. The reduction in debt levels properly positions the Corporation for periods of lower commodity prices.

During 2000, the Corporation converted the entire term portion of its operating line into a revolving operating line. The borrowing base is currently set at $48,000,000.

A history of the Corporation's debt is as follows:

Continuity of Long-term Debt	
Balance, December 31, 1997	NIL
Convertible debentures issue	$ 2,000,000
Vendor debt financing (US$ notes) on Sembakung acquisition	24,575,000
Balance, December 31, 1998	26,575,000
Bank financing on Canadian asset acquisition	45,000,000
Vendor financing on Canadian asset acquisition	9,666,000
Issue of US$ notes	1,411,000
Foreign exchange gains on US$ notes	(1,264,000)
Repayment of Sembakung vendor financing	(3,067,000)
Repayment of bank debt	(3,000,000)
Conversion of convertible debentures	(1,650,000)
Balance, December 31, 1999	73,671,000
Foreign exchange losses on US$ notes	801,000
Repayment of Sembakung vendor financing	(4,348,000)
Repayment of bank debt	(4,500,000)
Conversion of convertible debentures	(350,000)
Balance, December 31, 2000	**$ 65,274,000**

Debt outstanding increased from nil in 1997 to $24,575,000 due to the Sembakung acquisition in September of 1998. Debt outstanding increased by $54,966,000 in 1999 due to the acquisition of the Western Canadian assets. During 1999 and 2000, $7,500,000 of long-term bank debt was repaid and a $2,000,000 debenture was converted into common shares. Subsequent to December 31, 2000, the balance the Corporation's Sembakung vendor financing was repaid, reducing corporate debt by approximately $13,000.000.

Business Risks

The oil and gas business is fraught with risks, including but not limited to operational, financial, and political and regulatory risks.

Operational Risks

Operational risks include geological interpretation, down hole operations, drilling of wells, and processing and delivery of commodities. The key element in controlling operational risks is to recruit and retain top quality and experienced professional staff. This is accomplished by establishing compensation arrangements competitive in our industry and community, and by providing employees with a challenging and professional work environment. In addition, other methods of mitigating operational risks include:

- maintaining a diversified high quality asset base;
- maintaining appropriate emergency response plans; and
- maintaining prudent levels of insurance.

The Corporation acknowledges these risks and has an ongoing comprehensive review process to monitor these risks.

Financial Risks

Financial risks include commodity prices, exchange rates, interest rates and availability of capital resources. The Corporation addresses these risks by:

- utilizing derivatives where appropriate to provide certainty of cash flow;
- maintaining a prudent level of equity on the balance sheet; and
- maintaining both US dollar and Canadian dollar debt structures.

The derivative hedge transactions in place are detailed in Note 12 to the Consolidated Financial Statements.

Management's Report

To the Shareholders of Equatorial Energy Inc.:

The consolidated financial statements of Equatorial Energy Inc. were prepared by and are the responsibility of management. The statements have been prepared in conformity with the Canadian generally-accepted accounting principles appropriate in the circumstances and include some amounts that are based on management's best estimates and judgements.

The Corporation maintains systems of internal accounting controls designed to provide reasonable assurance that all transactions are properly recorded in the Corporation's books and records, that policies and procedures are adhered to, and that assets are protected from unauthorized use. The systems of internal accounting controls are complemented by the selection, training and development of professional financial managers.

The consolidated financial statements have been audited by the independent accounting firm, Deloitte & Touche LLP, whose appointment will be ratified yearly by the shareholders at the annual shareholders' meeting. The independent accountants conduct a review of internal accounting controls to the extent required by generally-accepted auditing standards and perform such tests and related procedures as they deem necessary to arrive at an opinion on the fairness of the financial statements.

The Audit Committee of the Board of Directors periodically meets with the independent accountants and management to satisfy itself that it is properly discharging its responsibilities. The independent accountants have unrestricted access to the Audit Committee, without management present, to discuss the results of their examination and the quality of financial reporting and internal accounting control.

David N. Matheson
President and Chief Executive Officer
March 1, 2001

John R. Rooney
Senior Vice-President and Chief Financial Officer

Auditors' Report

To the Shareholders of Equatorial Energy Inc.:

We have audited the consolidated balance sheets of Equatorial Energy Inc. as at December 31, 2000 and 1999 and the consolidated statements of income and retained earnings and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2000 and 1999 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP
Chartered Accountants
Calgary, Alberta
February 20, 2001 (except for Note 15, which is dated March 1, 2001)

consolidated balance sheets

December 31 (000s)	2000	1999
Assets		
Current		
Cash	$ 4,485	$ 8,156
Accounts receivable	28,469	13,267
	32,954	21,423
Petroleum and Natural Gas Interests (Note 4)	129,896	109,829
	$ 162,850	$ 131,252
Liabilities		
Current		
Accounts payable and accrued liabilities	$ 24,981	$ 17,847
Current portion of long-term debt (Note 5)	17,990	5,017
	42,971	22,864
Long-term Debt (Note 5)	47,284	68,654
Future Income Taxes (Note 10)	27,959	7,604
Site Restoration and Abandonment	2,119	1,821
Shareholders' Equity		
Share capital (Note 6)		
Common shares	18,544	16,513
Series 1 convertible preferred shares	12,000	12,000
Retained earnings	11,973	1,796
	42,517	30,309
Commitments and contingency (Notes 12 and 13)	$ 162,850	$ 131,252

See accompanying notes

On behalf of the Board

G. Marshall Abbott, Director

David N. Matheson, Director

consolidated statements of income and retained earnings

Years Ended December 31 (000s)	2000	1999
Revenue		
Gross oil and natural gas revenue	$ 128,582	$ 72,257
Royalties and government share	(40,847)	(25,515)
	87,735	46,742
Expenses		
Operating	25,310	20,169
Depletion, depreciation and amortization	21,638	14,365
Interest – long-term debt	6,619	6,494
Administrative	5,716	3,253
Foreign exchange and other	(489)	(595)
	58,794	43,686
Income Before Income Taxes	28,941	3,056
Income Taxes (Note 10)	14,848	600
Net Income for the Year	14,093	2,456
Retained Earnings (Deficit), Beginning of Year	1,796	(25,967)
Adjustment for change to future tax accounting (Note 10)	(3,136)	–
Dividends paid on preferred shares (Note 6)	(780)	(660)
Reduction of common share stated capital (Note 6)	–	25,967
Retained Earnings, End of Year	$ 11,973	$ 1,796
Net income per common share – basic (Note 8)	$ 0.70	$ 0.13
Net income per common share – fully diluted (Note 8)	$ 0.51	$ 0.12

consolidated statements of cash flows

Years Ended December 31 (000s)	2000	1999
Cash Flows from the Following:		
Operating Activities		
Net income for the year	$ 14,093	$ 2,456
Items not affecting cash:		
Depletion, depreciation and amortization	21,835	14,365
Future income taxes	14,418	1,100
Unrealized foreign exchange losses (gains)	132	(652)
Cash flow from operations	50,478	17,269
Changes in non-cash working capital (Note 11)	(8,068)	838
	$ 42,410	$ 18,107
Financing Activities		
Repayment of long-term debt	$ (8,848)	$ (6,067)
Dividends paid on preferred shares	(780)	(660)
Issue of common shares (net of issue expenses)	338	12,495
Deferred financing charges	(51)	(643)
Issue of bank debt	–	45,000
Issue of US$ notes	–	1,411
	(9,341)	51,536
Investing Activities		
Petroleum and natural gas expenditures	(41,496)	(19,831)
Site restoration and abandonment	(1,253)	(187)
Proceeds on sale of petroleum and natural gas interests	5,522	2,000
Purchase of petroleum and natural gas interests (Note 3)	–	(48,502)
	(37,227)	(66,520)
Foreign exchange loss (gain) on long-term debt – deferred	487	(611)
Net (Decrease) Increase in Cash	(3,671)	2,512
Cash, Beginning of Year	8,156	5,644
Cash, End of Year	$ 4,485	$ 8,156
Cash flow from operations per common share – basic (Note 8)	$ 2.62	$ 1.20
Cash flow from operations per common share – fully diluted (Note 8)	$ 1.79	$ 0.83

Notes to Consolidated Financial Statements

Years Ended December 31, 2000 and 1999
(Tabular amounts are in thousands of dollars except for share and per share amounts)

1. Nature of Business

Equatorial Energy Inc., and its subsidiaries (the "Corporation"), is in the business of exploration for and development of petroleum and natural gas interests.

2. Significant Accounting Policies

(a) Basis of presentation

The consolidated financial statements are presented in accordance with Canadian generally accepted accounting principles and are expressed in Canadian dollars.

(b) Basis of consolidation

The consolidated financial statements include the accounts of the Corporation and its wholly owned subsidiaries Equatorial Energy (International) Inc. ("EQII"), Equatorial Energy Trading Corp. ("EETC"), Pilona Petro Tanjung Lontar Ltd. ("Pilona"), Equatorial Energy (Indonesia) Inc. ("EEII") (formerly Energy Process Services Ltd.) and Auckland Investments Pty. Ltd. The consolidated financial statements also include the accounts of its 80% owned subsidiary, Perkasa Equatorial Sembakung Ltd. ("Perkasa"). All intercompany transactions and accounts have been eliminated.

(c) Cash

Cash includes short-term investments with a maturity of ninety days or less at the time of issue.

(d) Petroleum and natural gas interests

The Corporation follows the full cost method of accounting for petroleum and natural gas interests whereby all costs of exploring and developing petroleum and natural gas reserves, net of government grants, are capitalized by individual country cost centre. Such costs include land acquisition costs, geological and geophysical expenses, costs of drilling both productive and non-productive wells, tangible equipment and overhead charges directly related to acquisition, exploration and development activities.

For each cost centre, the total carrying value of the Corporation's petroleum and natural gas interests, less accumulated depletion and depreciation, is limited to the estimated future net revenue from production of proven reserves, based on unescalated prices and costs plus the lower of cost and net realizable value of unproved properties, less estimated future development costs, site restoration and abandonment costs, general and administrative expenses, financing costs and income taxes. The carrying value of unproved properties is reviewed periodically to ascertain whether impairment has occurred. If impairment occurs, the costs will be written down to their net realizable value.

In Indonesia, the Corporation has no ownership interest in the producing assets nor in the oil and gas reserves, but rather has the right to operate the assets and receive production and/or revenues from the sale of oil and gas in accordance with the petroleum sharing agreements. Proved reserves have therefore been determined on a net entitlement basis, which takes into account projections of the government's share of production calculated with certain price and expenditure assumptions.

For each cost centre, the costs associated with proved reserves are depleted or depreciated using the unit-of-production method based on an independent engineering estimate of proved reserves, before royalties and government share, with natural gas converted to its energy equivalent at a ratio of six thousand cubic feet of natural gas to one barrel of oil.

The Corporation provides for future estimated site restoration costs using the unit-of-production method based on costs and regulations in effect at the end of the year.

Office equipment is amortized on a straight-line basis over five years.

(e) Government share

All operations conducted jointly with the Indonesian national oil company ("Pertamina") are reflected in these financial statements. All Pertamina interests, other than income taxes, are considered to be government share. Government share on production from Indonesian properties represents the entitlement of Pertamina to a portion of the production of crude oil, liquids and natural gas production and are recorded using rates in effect under the terms of contracts at the time of production.

Under the terms of each contract, the Corporation is entitled to use gross proceeds of production to recover substantially all of the non-capital costs incurred during each year as well as current year depreciation for capital costs and any costs unrecovered from prior years. Such gross proceeds of production are included in revenue before government share.

The maximum cost recovery in any year is 80% of gross revenue for the first two years of production, and depending on the production sharing contract, 65% to 80% thereafter. Pertamina and the Corporation share the remaining oil profits based upon the terms in each contract. The Corporation's pre-tax profit share on oil production is generally the rate that will provide an after-tax profit share of 15%.

(f) Foreign currency translation

Transactions of the Corporation that are denominated in foreign currencies are recorded in Canadian dollars at exchange rates in effect at the related transaction dates. Monetary assets and liabilities denominated in foreign currencies are adjusted to reflect exchange rates at the balance sheet date. Non-monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate in effect when the assets were acquired or the liabilities assumed. Exchange gains and losses arising on the translation of monetary assets and liabilities are included in the determination of income for the year with the exception of unrealized gains or losses on translation of long-term monetary liabilities, which are deferred and amortized over the remaining term of such liabilities.

(g) Stock based compensation plans

The Corporation has stock based compensation plans as described in Note 7. No compensation expense is recognized when stock options are issued. Consideration paid on exercise of stock options is credited to share capital. The Corporation may grant share appreciation rights as described in Note 7. The cost of such rights is accrued over the period it relates to and accounted for as an expense.

(h) Flow-through shares

Under the terms of Canadian flow-through share legislation, the tax attributes of qualifying expenditures are renounced to subscribers. To recognize the foregone tax benefits, the share capital is reduced and a future income tax liability is recorded as the related expenditures are made.

(i) Joint venture activities

The Corporation's exploration and development activities are conducted jointly with others, and accordingly, the accounts reflect only the Corporation's proportionate interest in such activities.

(j) Income taxes

The Corporation has adopted, on a retroactive basis and without restatement of 1999 consolidated financial statements, the new accounting recommendation of the Canadian Institute of Chartered Accountants, "Income Taxes". Under this method, future income tax assets and liabilities are measured based upon temporary differences between the carrying values of assets and liabilities and their tax basis. Income tax expense (recovery) is computed based on the change during the year in the future tax assets and liabilities. Effects of changes in tax laws and tax rates are recognized when substantially enacted.

3. Purchase of Western Canadian Oil and Gas Properties

On February 26, 1999, the Corporation closed the purchase of certain Western Canadian oil and gas properties. Revenues and expenses for the properties have been recorded effective from January 1, 1999. Consideration given was as follows:

	$
Cash, net of accrued cash flow from October 1, 1998 to December 31, 1998	47,045
Interest due on purchase price from October 1, 1998 to December 31, 1998	1,457
Total cash consideration	48,502
Convertible preferred shares (Note 6)	12,000
Promissory note (Note 5)	9,666
	70,168

The entire amount of $70,168,000 was allocated to the Corporation's petroleum and natural gas interests.

4. Petroleum and Natural Gas interests

	Cost	Accumulated Depletion and Depreciation	Net Book Value
2000			
Petroleum and natural gas interests	$ 181,194	$ (51,612)	$ 129,582
Other assets	619	(305)	314
	$ 181,813	$ (51,917)	$ 129,896
1999			
Petroleum and natural gas interests	$ 141,041	$ (31,697)	$ 109,344
Other assets	619	(134)	485
	$ 141,660	$ (31,831)	$ 109,829

As at December 31, 2000, unproved properties with capitalized costs of $20,817,016 (1999 – $16,976,464) for Indonesian properties and $17,500,000 (1999 – $18,551,500) for Canadian properties were not subject to depletion.

During the year ended December 31, 2000 the Corporation capitalized overhead charges related to petroleum and natural gas exploration and development activities of $2,880,421 (1999 – $2,419,000).

5. Long-term Debt

	2000	1999
Revolving bank credit facility with interest accruing monthly at the Corporation's choice of any of the following rates: Canadian prime plus 1%, U.S. Base rate plus 1%, LIBOR rate plus 2% or Bankers' Acceptance rate plus 2% quarterly. There are no principal repayments required until maturity in 2004. The loan is secured by a fixed and floating charge debenture over the Western Canadian oil and gas properties (see Note 3) and by a general security agreement.		
The Corporation's banker has been granted priority over all assets other than the Corporation's existing rights and interests in Indonesia.	$ **37,500**	$ 42,000
Promissory notes of US$11,682,421 (1999 – US$14,373,614), due on March 28, 2001. Simple interest accrues at 10% and is paid quarterly.		
The notes are secured by a pledge of the shares of EEII and a security interest in the shares of EQII. In the event the Corporation defaults on the payment of principal of the notes, the unpaid principal plus accrued interest can be immediately converted, at the option of the noteholder, into common shares based upon the market price prevailing at the time of the default.	**17,518**	20,746
Promissory note due on the later of February 25, 2005 and one day following the repayment by the Corporation of all amounts owing under its existing bank agreements. Interest accrues and is paid quarterly at 7.2% per annum. The Corporation may pre-pay any or all of the outstanding principal and interest, but must, in certain circumstances, pay a pre-payment premium of 8.89% which declines by 2.22% per calendar year until it becomes 1.11% in 2005 and expires thereafter. In the event of certain events of default, the note and any accrued interest is convertible, at the option of the vendor, into common shares at a price of $2.2712 per share.	**9,666**	9,666
US$630,000 non-interest bearing promissory note, payable in equal monthly installments of US$26,250 over 24 months, with the first installment due on February 9, 2000.	**590**	909
Convertible debenture	**–**	350
	65,274	73,671
Less: current portion	**(17,990)**	(5,017)
	$ **47,284**	$ 68,654

At December 31, 2000, $497,000 (net of accumulated amortization of $292,000) of financing costs have been deferred and will be amortized over the remaining terms of the related debt

6. Share Capital

(a) Authorized

Unlimited number of common shares without par value

Unlimited number of preferred shares without par value

(b) Issued

	Number of Shares	$
Common Shares		
Balance at December 31, 1998	10,766,388	32,047
Reduction of common share stated capital	–	(25,967)
Issued for cash		
On exercise of Special Warrants	4,395,000	8,790
Flow-through common shares	2,234,900	4,805
Issued on conversion of debentures	1,155,000	1,650
Issued for services	150,000	307
Tax benefits renounced to flow through investors	–	(3,712)
Common share issue expenses	–	(1,407)
Balance at December 31, 1999	18,701,288	16,513
Adjustment for change to future tax accounting	–	3,468
Issued for cash		
Exercise of common share purchase options	126,125	177
Exercise of common share purchase warrants	92,500	203
Issued on conversion of debentures	245,000	350
Tax benefits renounced to flow through investors	–	(2,144)
Common share issue expenses (net of tax)	–	(23)
Balance at December 31, 2000	19,164,913	18,544
Series 1 Convertible Preferred Shares		
Issued on purchase of petroleum and natural gas interests (Note 3)	21,134,203	12,000

(c) Common share consolidation and reduction of stated capital

At the Corporation's annual and special meeting held on June 24, 1999, its shareholders approved the consolidation of the issued and outstanding common shares on a one-for-four basis. Accordingly, any reference to the historical number of common shares has been adjusted to reflect this consolidation. The shareholders also approved the application of the December 31, 1998 deficit of $25,967,000 against issued share capital at that date.

(d) Issue of Special Warrants

On May 21, 1999, the Corporation completed a private placement of 4,395,000 special warrants (the "Special Warrants") at $2.00 per Special Warrant for gross proceeds of $8,790,000. Each Special Warrant was exercisable, at no additional cost, into one common share and one-half of one warrant. Each whole warrant was exercisable into one common share, at $2.60 per share, for a period of three years. All of the Special Warrants were exercised on May 27, 1999.

The Corporation's Agent for the private placement was paid an average cash commission of 5.0% of the gross proceeds and received compensation warrants which were exercised, for no additional consideration, into 250,000 warrants.

(e) Flow-through Shares

At December 31, 1999 and 1998, a total of $4,805,035 and $3,712,550, respectively, of Canadian Exploration Expenses were renounced to shareholders. The related expenditures were incurred during the following year.

(f) Series 1 Convertible Preferred shares

The preferred shares were issued to the vendor of the Corporation's Western Canadian petroleum and natural gas properties, (Note 3), and bear dividends at 6.5% per year. The preferred shares are convertible, at the vendor's option, into a maximum of 5,283,550 Common Shares.

The Corporation can force conversion if the weighted average trading price of the Corporation's common shares is at least $3.4068 for ten consecutive trading days. Redemption by the Corporation is subject to a redemption premium of 8% at January 1, 2001 that declines by 2% per calendar year until 2005 when it declines at 1% until it expires in 2006. The preferred shares also entitle the vendor to appoint one director to the Board of Directors of the Corporation. If the Corporation fails to either pay two consecutive dividend payments or comply with certain financial covenants, the vendor can convert all or a portion of the preferred shares into common shares, based upon the market price for the Corporation's common shares prevailing at the time of default. In the event of default, the vendor shall also be entitled, until such time as the preferred shares are converted into common shares, to elect two thirds of the Corporation's Board of Directors.

(g) Warrants

The following warrants for purchase of common shares are outstanding at December 31, 2000:

Date Granted	Number of Common Shares	Exercise Price	Expiry Date
May 21, 1999	2,142,500	2.60	May 21, 2002
February 26, 1999	250,000	2.60	February 25, 2002

No value has been ascribed to any of the warrants for accounting purposes.

7. Stock Option and Share Appreciation Rights Plans

(a) Stock Option Plan

Under the Corporation's stock option plan, the Corporation may grant options to its directors, officers, employees and service providers to purchase common shares at a fixed price not less than the fair market value of the stock on the day preceding the grant date. The maximum term of the options is 10 years. The options are exercisable as to 25% per year beginning on the date of grant.

Options	Number	Weighted Average Exercise Price ($)
Outstanding at December 31, 1998	447,500	6.38
Granted during the year	1,558,750	1.40
Cancelled during the year	(293,750)	6.20
Outstanding at December 31, 1999	1,712,500	1.62
Granted during the year	417,500	1.99
Exercised during the year	(126,125)	1.40
Cancelled during the year	(238,375)	1.41
Outstanding at December 31, 2000	1,765,500	1.75
Exercisable at December 31, 2000	808,375	1.93

All numbers of options and prices prior to the share consolidation have been adjusted to reflect such consolidation.

During 1999, 93,750 of the outstanding options at December 31, 1998 with an exercise price of $6.20 were repriced to $1.40. The impact of the repricing has been reflected in the weighted average exercise price of options outstanding at December 31, 2000 and 1999. None of these were held by officers or directors.

The following table summarizes information about the Corporation's stock options outstanding at December 31, 2000.

Exercise Price ($)	Options Outstanding at 12/31/00	Remaining Contractual Life (years)	Options Exercisable at 12/31/00
1.40	1,243,000	3.50	621,500
1.45	45,000	4.00	22,500
1.85	10,000	4.00	2,500
1.76	159,500	4.30	39,875
2.05	160,000	4.50	40,000
2.30	78,000	4.70	19,500
2.35	10,000	4.50	2,500
6.20	10,000	1.70	10,000
7.80	50,000	1.10	50,000
1.40 - 7.80	1,765,500	3.66	808,375

(b) Share Appreciation Rights Plan

Under the Corporation's share appreciation rights plan, the Corporation may grant share appreciation rights to its directors, officers, employees or providers of services. Each right entitles the participant to receive from the Corporation an amount equal to the positive difference, if any, obtained by subtracting the assigned amount from the simple average of the closing trading price of the common shares on the TSE for the 20 trading days immediately preceding the date of exercise.

The following table summarizes information about the Corporation's share appreciation rights plan at December 31, 2000.

Base Value	Number	Remaining Contractual Life (years)	Terms
1.40-1.45	822,500	6.70	25% exercisable immediately on the agreement date with an additional 25% on the next 3 anniversary dates
2.30	167,500	7.70	25% exercisable on each of the first 4 anniversary dates
	990,000	6.87	

In 2000, $138,904 (1999 – $9,293) has been recorded as expense.

8. Per Share Amounts

Net income and cash flow per common share figures have been calculated using the following numbers of shares:

	2000	1999
Weighted average shares – basic	**18,978,559**	13,857,762
Weighted average shares – fully diluted		
– net income per common share	**28,522,010**	17,696,973
– cash flow per common share	**28,522,010**	22,215,421

Net income and cash flow figures have been reduced by preferred share dividends for purposes of the basic per common share calculations.

9. Segment Information

The Corporation's activities are conducted in two geographic segments, both relating to the exploration, development, and production of oil and natural gas.

The Corporation's two segments operate in Canada and Indonesia. The Corporation's head office is in Canada.

Revenues and Expenses	Canada ($) 2000	Canada ($) 1999	Indonesia ($) 2000	Indonesia ($) 1999	Total ($) 2000	Total ($) 1999
Gross oil and natural gas revenue	**75,753**	45,420	**70,205**	29,295	**145,958**	74,715
Royalties and government share	**(15,376)**	(8,796)	**(25,471)**	(16,719)	**(40,847)**	(25,515)
	60,377	36,624	**44,734**	12,576	**105,111**	49,200
Operating	**13,142**	11,111	**12,168**	9,058	**25,310**	20,169
Depletion and depreciation	**10,064**	10,514	**11,574**	3,851	**21,638**	14,365
Segment operating income (loss)	**37,171**	14,999	**20,992**	(333)	**58,163**	14,666
Hedging losses					**17,376**	2,458
Interest – long-term debt					**6,619**	6,494
Administrative					**5,716**	3,253
Foreign exchange and other					**(489)**	(595)
Income before income taxes					**28,941**	3,056
Income taxes					**14,848**	600
Net income					**14,093**	2,456

	2000 ($)	1999 ($)
Additions to petroleum and natural gas interests		
Canada	**12,810**	58,138
Indonesia	**24,417**	8,382
	37,227	66,520
Petroleum and natural gas interests		
Canada	**74,898**	68,244
Indonesia	**54,998**	41,585
	129,896	109,829

10. Income Taxes

Effective January 1, 2000, the Corporation adopted the new accounting recommendation of the Canadian Institute of Chartered Accountants, "Income Taxes". The standard has been adopted retroactively without restatement of the 1999 consolidated financial statements, with previously unrecognized future income tax liabilities relating to prior years being charged against the Corporation's opening retained earnings for 2000. In addition, the carrying value of petroleum and natural gas interests was increased and a future tax liability was recorded relating to the foregone tax benefits of Canadian flow-through renouncements previously recorded using the deferral method.

The impact of adopting the liability method was to record a future income tax liability of $3,380,090, decrease retained earnings by $3,136,090, increase share capital by $3,468,550 and increase petroleum and natural gas interests by $3,712,550.

Had the new method not been adopted the net income for 2000 would have been lower by $816,000.

The future income tax provision for 2000 varies from the amount that would be computed by applying the combined Canadian statutory income tax rates to the loss before taxes as follows:

	2000 ($)	1999 ($)
Income before income taxes	**28,941**	3,056
Expected income taxes at the Canadian statutory rate of 44.62%	**12,913**	1,375
Increase (decrease) in income tax expense resulting from		
Non-deductible Canadian crown charges	**6,076**	3,160
Canadian resource allowance	**(5,599)**	(2,718)
Canadian large corporation tax and provincial capital tax	**429**	408
Non-deductible amounts	**679**	1,293
Effect of higher tax rates in Indonesia	**350**	–
Utilization of previously unrecognized tax loss	**–**	(1,703)
Recovery on previously recorded tax provision	**–**	(1,215)
	14,848	600

The major components of the future income tax liability at December 31, 2000 are as follows:

	$
Property and equipment	26,396
Deferred charges	17,091
Future site restoration	(945)
Canadian non capital losses and other deductions carried forward	(13,794)
Share issue costs	(789)
Balance, December 31, 2000	27,959

The Corporation's non-capital losses for Canadian income tax purposes of approximately $28,300,000 million are available to be carried forward to offset income in future years and expire between 2005-2007.

11. Statements of Cash Flows

	2000 ($)	1999 ($)
Changes in non-cash working capital:		
Accounts receivable	**(15,202)**	(7,880)
Accounts payable and accrued liabilities	**7,134**	8,717
	(8,068)	838
Cash interest paid during the year	**6,422**	6,353
Cash taxes paid during the year	**429**	409

12. Hedging and Financial Instruments

The Corporation's financial instruments recognized on the balance sheet include cash, accounts receivable, accounts payable and accrued liabilities and long-term debt. The fair values of financial instruments other than long-term debt approximate their carrying amounts due to the short-term nature of these instruments.

At December 31, 2000, the Corporation had $37,500,000 million of variable rate bank loans. There were no instruments in place at December 31, 2000 or 1999 to fix the interest rate on this variable rate debt. At December 31, 2000 and 1999 the reported value of the long-term debt approximates fair value.

The Company has debt denominated in both US dollars and Canadian dollars. In addition, the Company's revenue stream is essentially based in US dollars although the Company reports in Canadian dollars. The Company has no instruments in place at December 31, 2000 to fix the exchange rates on these items.

The nature of the Corporation's operations results in exposure to fluctuations in commodity prices. The Corporation enters into derivative contracts to manage its exposure to commodity price risks.

The Corporation is exposed to credit-related losses in the event of non-performance by counter-parties. Hedge contracts have been entered into with the bank that has provided the revolving bank credit facility. The Company remains exposed to credit-related losses with all other counter-parties.

The Corporation has entered into natural gas and crude oil contracts for 2000 and future years as follows:

Delivery period	Quantity per day	Price	Nature of Contract
Gas			
January 1, 2001 to March 31, 2001	13,000 mmbtu	US$2.25	Swap
April 1, 2001 to June 30, 2003	13,000 mmbtu	US$2.40	Sold a call
Oil			
January 1, 2001 to April 30, 2001	500 bbls	US$14.00	Swap
May 1, 2001 to April 30, 2004	500 bbls	US$18.65	Sold a call

13. Contingency

Contingent consideration of US$3,000,000 is payable for the 1998 purchase of an Indonesian Technical Assistance Contract ("TAC"), over the life of that TAC. This amount is payable if petroleum property achieves the following average daily production targets for a 30 day period as follows:

a) 7,500 barrels of oil per day – US$1,000,000 plus accrued interest

b) 10,000 barrels of oil per day – US$1,000,000 plus accrued interest

c) 12,000 barrels of oil per day – US$1,000,000 plus accrued interest

This consideration is secured by a promissory note due 30 days after each target is met. The additional cost represented by these notes will be recorded as petroleum and natural gas interests by the Corporation at that time. Interest at Chase Manhattan bank prime plus 3% accrues from September 14, 1998 to the due date.

14. Comparative Figures

Certain of the comparative figures have been reclassified to conform to the presentation adopted for current year.

15. Subsequent Event

On January 31, 2001 the Corporation agreed to issue up to 3,350,000 Special Warrants. On February 14, 2001, the Corporation issued 2,000,000 Special Warrants, which entitle the holder to receive 2,000,000 common shares at a price of $2.60 per share, resulting in total gross proceeds to the Company of $5,200,000. On March 1, 2001, the Corporation issued an additional 1,350,000 Special Warrants, which entitle the holder to receive 1,350,000 flow through common shares at a price of $3.25 per share, resulting in gross proceeds of $4,387,500.

Glossary

API gravity: the American Petroleum Institute's standard for weight per unit of volume of crude oil, given in degrees — higher API gravity crude is more valuable

bcf: billion cubic feet

bcfpd: billion cubic feet per day

boe: barrel of oil equivalent

boepd: barrels of oil equivalent per day

bopd: barrels of oil per day

mcf: thousand cubic feet

mD: millidarcy, a measurement of permeability

mcfpd: thousand cubic feet per day

mmbtu: millions of British thermal units

mmcf: million cubic feet

mmcfpd: million cubic feet per day

mboe: thousands barrels of oil equivalent

mstb: thousands stock tank barrels

ooip: original oil in place

stb: a stock tank barrel is a barrel of oil at the earth's surface – stock tank oil lacks much of the dissolved gas present at reservoir pressure and temperatures

Board of Directors

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Chairman of the Board of
Equatorial Energy Inc.

David N. Matheson
President and Chief Executive Officer,
Equatorial Energy Inc.

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Partner, Bennett Jones,
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David N. Matheson
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John R. Rooney
Senior Vice-President and
Chief Financial Officer

Michael M. Machalski
Chief Operating Officer, Canada

Notes:
1. Audit Committee
2. Compensation Committee
3. Reserves Committee

Solicitors

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Calgary, Alberta

Bankers

The Chase Manhattan Bank of Canada
Bank One Canada

Auditors

Deloitte & Touche LLP
Calgary, Alberta

Independent Reservoir Consultants

Gilbert Lausten Jung Associates Ltd.
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Transfer Agent

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Annual General Meeting

3:00 p.m. April 26, 2001
The Metropolitan Centre
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